WHITE PAPER:

Update on Application of §29 Tax Credit to Coal Seam Gas

September 30, 1998

ACKNOWLEDGEMENTS

This report was prepared under Work Assignment No. 4-1 of U.S. Environmental Protection Agency Contract 68-W5-0017 by Greg A. Sanderson and Lesley W. Berggren of Gomel & Davis, LLP, Attorneys at Law, Atlanta, Georgia, under contract to Alternative Energy Development, Inc., Silver Spring, Maryland. This report is a technical document meant to be used for information dissemination.

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ABSTRACT

The §29 income tax credit may be claimed on the sale of coalbed methane produced before 2003 from certain wells drilled prior to 1993. This paper discusses the history of §29, and addresses the elements generally required for a wellbore to be grandfathered as a pre-1993 well eligible for §29. Other §29 requirements and limitations also are discussed, including recent developments with respect to well certifications by the Federal Energy Regulatory Commission (FERC), as well as using the §29 credit to raise project capital, a technique commonly referred to as “monetization” of the §29 credit.

Table of Contents

I. INTRODUCTION

Owners of wells which produce coalbed methane may be eligible for a special tax credit under Internal Revenue Code §29(a). The §29 credit is a production-based incentive that is allowed for producing and selling alternative or high-cost fuels, such as coalbed methane. The current value of the credit is in excess of $1.00 per each 1.0 million Btu's produced and sold. This paper is intended to enable owners of such wells to determine if they qualify or could qualify for the tax credit. Additionally, this paper will explain what additional steps some well owners must take in order to qualify for and benefit from the tax credit. To better understand §29 requirements, an overview of its background and history will be discussed. Following the general background will be sections discussing the procedural requirements of establishing a qualifying coal seam, along with a discussion of which well recompletions may qualify for the credit. The structural requirements and limitations will next be discussed. Finally, this paper will explain how a current owner may be able to monetize the §29 credit, and will present a hypothetical transaction for illustrative purposes.

II. BACKGROUND OF §29 AND CONGRESSIONAL HISTORY

Section 29(a) of the Internal Revenue Code allows a credit for qualified fuels sold by a taxpayer to an unrelated person during the tax year, the production of which is attributable to the taxpayer. The credit for the tax year is an amount equal to $3.00, as adjusted for inflation after 1979, multiplied by the barrel-of-oil equivalent of qualified fuels sold. After the 1997 inflation adjustment, the credit was approximately $1.05 per each 1.0 million Btu's produced and sold.

Section 29 was enacted as part of the Crude Oil Windfall Profit Tax Act of 1980 (originally designated as Code §44D and later redesignated as Code §29). To fully understand the true intent of §29, one must comprehend the policy behind the Crude Oil Windfall Profit Tax Act. Throughout the 1970's, the price of most crude oil and refined petroleum products was regulated. In April 1979 President Carter announced that he intended to phase out oil price controls by September 30, 1981. It was anticipated that oil producers would realize much greater profits, or "windfall profits" on the sale of petroleum fuels after elimination of price controls. The House Ways and Means Committee reported the condition of the oil market in 1979:

> In the short term, oil is characterized by what economists call "inelastic" supply and demand, which means that neither demand for oil nor production of it respond significantly to changes in oil prices in the short run. (In the longer term, the response may be much greater, but the extent of this response is a controversial issue.) Because both supply and demand are so insensitive to price changes in the short term, relatively small shifts in either supply or demand are capable of producing large swings in prices.
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> Between 1972 and 1978, the price of imported oil (including transportation costs) rose from about $3 per barrel to $14 per barrel. Currently the price is close to $20 per barrel, and it may go still higher by year end. (In the Rotterdam spot market, crude oil prices exceed $30 per barrel.) The proximate cause of these price increases has been the action of the OPEC cartel in setting high prices and restricting production to sustain the high price. However, the rapid growth of demand

> for oil will continue to be such as to permit continued high and rising prices, either as a result of market forces, the actions of the OPEC cartel, or both.
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> H. R. Ways and Means Rep. No. 304, 96th Congress, 1st Sess. 4, 6-7 (1979), 1980-3 C. B. 81, 90-91.

The Act sought to tax the windfall oil profits which would result from the absence of price controls in the "inelastic" oil market. The additional revenues raised by the tax were to be used for alternative energy sources to broaden the nation's energy production capacity and help alleviate the problems of relying on foreign oil:

> The committee believes that solving the energy problem requires major Federal aid for the development of alternative energy sources and new methods of energy conservation. To assure that these expenditures are met, the bill places the revenue from the windfall profit tax in an energy trust fund which will finance the needed energy spending programs.
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> Id. at 92.

Thus, the initial overriding policy of the Act was to divert monies from taxes levied on conventional fuels to use for the promotion of non-conventional fuels. The §29 credit became an important instrument for implementing the Act's policy. As originally enacted, a number of non-conventional fuels were eligible for credit:

> Eligible sources.-- The credit is available for the following forms of energy production:
>
> (1) oil from shale;
> (2) oil from tar sands;
> (3) natural gas from geopressured brine, coal seams, Devonian shale, or tight sands;
> (4) liquid, gaseous, or solid synthetic fuel, including petrochemical feedstocks, (other than alcohol) from coal liquefaction or gasification facilities;
> (5) gas from biomass (including wood);
> (6) steam from solid agricultural by-products; and
> (7) qualifying processed solid wood fuels.
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> H.R. Conf. Rep. No. 817, 96th Congress, 2d Sess. 87, 138 (1980), 1980-3 C.B. 245, 298.

When the Crude Oil Windfall Profit Tax Bill was before Congress, technologies were available to develop these fuel sources, but the technologies were not widely employed, either due to lack of research and testing or due to higher costs incurred to develop and market these resources when compared to conventional fuels. Consistent with the policy of the Act, the purpose of the §29 fuel credit was to encourage production and use of these alternative sources by decreasing their production costs relative to the price of conventional fuels, and permitting them to become competitive in the marketplace:

> The committee believes that a tax credit for the production of energy from alternative sources will encourage the development of these resources by decreasing the cost of their production relative to the price of imported oil.

> These alternative energy sources typically involve new technologies, and some subsidy is needed to encourage these industries to develop to the state where they can be competitive with conventional fuels. The information gained from the initial efforts at producing these energy sources will be of benefit to the entire economy.
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> * * * *
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> The United States possesses vast reserves of many of the alternative sources eligible for the credit, including oil shale, geopressured gas and coal. If the credit lends to the development of these alternative sources, it would make a major contribution to reducing our dependence on imported energy.
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> S. Rep. No. 394, 96th Congress,
> 1st Sess. 87 (1979), 1980-3 C.B. 131, 205.

III. GENERAL CRITERIA FOR COALBED METHANE

On December 31, 1992, the window closed for application of §29 to new coal gas wells. Only wells drilled by this date qualify for the §29 credit. Generally, coalbed methane may qualify for the §29 credit only if the following criteria are met:

1. The gas must be produced from qualifying coal seams, as determined under §503 of the Natural Gas Policy Act of 1978.
2. The gas must be produced from a well drilled during a period beginning January 1, 1980 and ending December 31, 1992.
3. Coal seam gas must not have been produced from the subject property in marketable quantities before January 1, 1980.
4. The gas must be produced and sold by December 31, 2002.

IV. ESTABLISHING A QUALIFYING COAL SEAM

To establish that the gas is derived from a coal seam, a taxpayer must obtain a "final determination" as to both the field and the individual well from a state or federal agency having regulatory jurisdiction with respect to the production of natural gas. This requirement is incorporated into §29 from §503 of the Natural Gas Policy Act of 1978 (NGPA). Any such agency making the determination is required to provide notice to the Federal Energy Regulatory Commission (FERC), which has the authority to review and reverse the determination. However, FERC stopped processing the determinations of local authorities involving both fields and individual wells on April 30, 1994. Despite this decision by FERC, the Internal Revenue Service will not issue a private letter ruling regarding prequalification for §29 credit without the FERC certification.

In a recent Tax Court decision, *Neilson-True Partnership v. Comm.*, 1997 U.S. Tax Ct. LEXIS 57; 109 T.C. No. 6 (Sept. 9, 1997), the court held that an individual well-category determination must be obtained under the procedures contained in NGPA §503 in order to qualify for the §29 tax credit attributable to tight formation gas. In that case, the taxpayer owned an interest in two wells in the same tight formation gas field. FERC made an administrative determination that the J-Sand

formation field was a tight formation and that the gas produced was tight-formation gas under the proper statutory procedure. The operator of the wells submitted a well-category determination to the proper local authority for one well, but failed to request a determination for the second well. The determination for the first well became final as it was not overturned by FERC. The Internal Revenue Service allowed the §29 credit for the first well. However, the Internal Revenue Service disallowed the claimed tax credits on the second well because no submission for a determination was made for that well. The taxpayer argued that the term "determination" in §29(c)(2)(A) did not result in the requirement for a well-category determination from FERC or under NGPA §503. Further, the taxpayer argued that the term was ambiguous and should be construed in light of the legislative history and the congressional intent in enacting the credit. The taxpayer concluded that the well should be allowed the credit without a formal procedural determination since it otherwise met the definitional requirements (of a tight formation gas producing well) under the statutes. The Internal Revenue Service argued that the statutes involved expressly and unambiguously require a well-category determination which must be obtained from the specified authorities before the well is entitled to a tax credit. The court agreed with the Internal Revenue Service.

The court reasoned that both §29 and NGPA §503 must be read together to fully understand the requirements and meaning of §29. NGPA §503 was the procedural mechanism for the determination of whether a particular well's production qualified for earlier gas price incentives available under the statute. In order to obtain the gas price incentives, a taxpayer had to comply with a mandatory four-step process. The court stated that this four-step process is also mandatory to receive the tax credit. The four-step process is as follows:

1. The taxpayer must obtain a local authority recommendation that a field be designated as a tight formation.
2. Notice of such recommendation must be sent to FERC. FERC can affirm, reverse, remand, issue a preliminary finding, or take no action as to the local authority recommendation. If no action is taken, then the local recommendation is final 45 days after receipt of the recommendation by FERC. If FERC issues a preliminary finding but fails to take further actions, then the local recommendation becomes final 120 days after the date FERC's preliminary finding was issued.
3. After the field is properly determined, an interested producer must petition the local authority for recommendation as to each particular well.
4. Again, notice of such recommendation must be sent to FERC. FERC can affirm, reverse, remand, issue a preliminary finding, or take no action as to the local authority recommendation as to a particular well. If no action is taken, then the local recommendation becomes final 45 days after receipt of the recommendation by FERC. If FERC issues a preliminary finding but fails to take further actions, then the local recommendation becomes final 120 days after the date FERC's preliminary finding was issued.

Thus, the court ruled that the taxpayer was not entitled to the §29 tax credit as no individual well determination had been made.

In a separate, earlier case, petitioners brought suit in federal court under the provisions of NGPA for review of FERC's refusal to accept state agency determinations that their wells produced tight formation gas. *Marathon Oil Co. v. FERC*, 68 F.3d 1376 (D.C. Cir. 1995). In that case, the petitioners had state agency determinations regarding tight gas well formations for wells recompleted after January 1, 1993. "Recompletion" means generally that a pre-existing well is repaired or redrilled to exploit previously untapped reserves. The petitioners sent such determination to FERC

for affirmation, for the tax credit. However, 70 days after receiving the state agency determination, FERC announced that it would not accept the designation because they were post-1992 recompletions. The petitioners were concerned that the Internal Revenue Service would disallow the §29 tax credit and brought this suit for review of FERC's actions. The court held that the petitioners had no standing because the determination by the state authority was not reversed or remanded, thus the petitioners were not injured by FERC's refusal to accept the state agency determinations. The court further stated that there was nothing to show that the Internal Revenue Service will not allow the credit without FERC approval and any such concern by the petitioners was merely speculation as to injury. The court based this on Revenue Ruling 93-54, which indicates that the Internal Revenue Service will consider recognizing a tax credit for gas from wells that would no longer be eligible to receive a tight formation gas designation from FERC. The Internal Revenue Service will allow a §29 tax credit even if a well is recompleted after 1992 so long as the recompletion does not involve additional drilling to deepen or extend the well. In contrast, FERC has a narrower definition of recompletion for purposes of §503. The court stated that the petitioners retained the right to present their arguments in the event that the Internal Revenue Service disallowed the §29 tax credit based on FERC's refusal to accept the state determinations, however they had not been injured by the mere refusal to review the state recommendation.

The court declined to discuss the procedural technicalities of the §503 mandatory four-step process in obtaining the tax credit as a result of FERC no longer reviewing local recommendations, nor did the court comment on the implications of the 70-day delay in responding to the state agency determination, even though the statute clearly states that FERC must respond within 45 days or the state determination is considered final.

Currently, the *Nielson-True* case is on appeal to the Tenth Circuit Court of Appeals. One issue to be considered is the Tax Court's interpretation of Revenue Ruling 93-54 and its application to the petitioner's case. The Tax Court assumed that Revenue Ruling 93-54 was premised on a final determination by FERC as to both the field and the individual well. In that Revenue Ruling, the Internal Revenue Service stated that the §29 tax credit was appropriate for a certain type of recompletion, although a FERC final determination would have been impossible to obtain under those same circumstances. The factual situation in Revenue Ruling 93-54 dealt with a recompletion after 1992 of a well that was drilled during the proper drilling window for the tax credit. FERC issued an order on July 12, 1993 stating that NGPA well category determination could not be obtained for recompletions commenced after 1992. This Revenue Ruling was published on August 16, 1993. Thus, the Internal Revenue Service appears to have premised its Revenue Ruling on the fact that an individual well certification by FERC was no longer possible.

Until the issue of FERC certification is decided by the courts, owners of otherwise qualified coalbed methane and tight formation gas properties who do not have FERC certification may wish to employ the following strategy in order to qualify for the §29 credit. The owner of the property should obtain a local authority designation of the field and of all individual wells, properly file the designation with FERC, and wait 45 days to see if any action is taken[1]. If no action is taken, the owner of the property will have a basis for claiming the §29 tax credit. The owner must then wait to see if the Internal Revenue Service conducts an audit regarding the §29 credit. If the Internal Revenue Service does conduct an audit regarding the §29 credit, the owner/taxpayer may argue that all procedural requirements for §29 had been met. This situation is distinguishable from the *Neilson-True*

[1] FERC Form 121 (no longer available) formerly was used for submission of local designations to FERC.

Partnership case, where the taxpayer allegedly violated the NGPA procedural requirements by failing to obtain an individual well designation, because here, the taxpayer will have complied with all procedural requirements.

V. DEFINING "WELL DRILLED" AND QUALIFYING RECOMPLETIONS UNDER REVENUE RULING 93-54

Section 29 does not define what constitutes a "well drilled" for purposes of meeting the 1980 through 1992 qualification period. However, the Internal Revenue Service has issued a number of rulings interpreting these terms. The Service, in a series of private letter rulings, defined the term "well" as a shaft capable of conducting liquids or gases from an underground reservoir to the surface. The term "drilled" was defined to essentially mean well completion, described as the construction of a conduit necessary for production of the underground resource.

Relying on these definitions, the Service issued private letter rulings in the 1980's which permitted old wellbores, originally drilled prior to 1980 for production of conventional oil and gas, to qualify as "wells drilled" during the qualification period when these wellbores were recompleted to extract coal seam gas. In the 1990's, the focus of Internal Revenue Service rulings shifted from the qualification of pre-1980 wellbores to the qualification of new drillings which would not be finished until after the applicable period of qualification. Generally, the Service held that a well would be considered drilled within the qualification period if it was "spudded in" by December 31, 1992, and there was continual drilling to the productive horizon. The application of this principle may be illustrated by the following two contrasting examples contained in Revenue Ruling 93-54:

> Example One. In 1982, the owner of an oil and gas property drilled a well for the purpose of producing crude oil. During the drilling and completion of the well, a coal seam gas deposit was penetrated above the oil reservoir. In 1994, when the crude oil was depleted, the owner plugged the oil zone. The owner then recompleted the well by perforating the casing and installing a flow line to extract gas from the coal seam deposit. The Service ruled that the taxpayer in this example qualified for §29 because the productive horizon of the coal seam was penetrated in the original drilling which occurred before the December 31, 1992 deadline.
>
> Example Two. In 1982, the owner of an oil and gas property drilled a well to 4,800 feet for the purpose of producing crude oil. In 1994, the crude oil was depleted. At that time, the owner deepened the well to 8,000 feet by additional drilling, and perforated qualifying gas below the depleted oil reservoir. The Service held that this taxpayer did not qualify for the §29 credit. Although the well was "spudded in" within the December 31, 1992 deadline, there was no continual drilling to reach the productive horizon of the qualified gas in the original drilling. Thus, the additional drilling in 1994 constituted a new well drilled after the qualifying deadline had passed.

Accordingly, a well drilled to the productive horizon of the coal seam within the qualifying period will potentially qualify. Possible applications at coal mines may include the following wellbores, provided they fall within the fact scenario of Example One above:

1. Conventional oil or natural gas wells;
2. Gob wells;
3. Utility wells; and
4. Mine ventilation wells or shafts.

Regardless of the purpose of the original drilling, the well or shaft must have penetrated the productive horizon of the coal seam gas by December 31, 1992, consistent with Example One above. If the well or shaft must be deepened, then it may not qualify, as illustrated by Example Two above. The only well that has been officially approved by the Internal Revenue Service is a conventional oil or natural gas well. Accordingly, a prudent strategy for employing one of the other potential applications would include filing an application for a private letter ruling from the Service regarding §29 qualification if the Service will agree to issue a ruling. As previously discussed, the Service will only rule if the taxpayer has FERC certification of the wells.

VI. MULTIPLE ZONE COMPLETIONS

Multiple zone completion describes a drilling technique which allows operators to simultaneously produce gas from a theoretically unlimited number of coal seams vertically dispersed over thousands of feet, using a single well head. Accordingly, multiple zone completion techniques allow operators to pursue a much broader target of coalbed methane formations than previously capable with single zone completion methods. The Service has ruled privately that the "productive horizon" or "targeted formation" of a well employing the multiple zone completion technique is not any one particular coal seam, but, instead, is the sum of the individual coal seams comprising the applicable formation. Thus, the gas which may qualify for the §29 credit from a multiple zone well is not limited to any particular coal seam or group of coal seams, as long as the gas is extracted from a formation targeted within the 1992 deadline.

Specifically, the Service ruled that the gas derived from a coal seam perforated, stimulated, and brought onto production after December 31, 1992 would qualify for the §29 credit, provided that (a) the well was spudded within the qualification period, (b) the coal seam was within the "productive" horizon targeted for possible stimulation at the time the well was spudded, and (c) the perforation and stimulation activities were continuously pursued in a diligent manner consistent with sound engineering and development practices.

VII. STRUCTURAL REQUIREMENTS AND LIMITATIONS

Once produced, the gas must be sold to an "unrelated" party in order to qualify for the §29 credit. Joint ventures, or partnerships, may qualify as "unrelated" provided that the gas producer does not exceed certain ownership thresholds in the venture or partnership. For example, in a brother-sister business structure, two companies may be considered "unrelated" if there is less then 80% common ownership of the two companies. In a parent-subsidiary structure, the parent company can own no more then 50% of the subsidiary. Other than the "sale" requirement of §29, there is no prohibition on where or how the gas is consumed, although it may be implied that the gas must be used for a legitimate business purpose.

The §29 credit is phased-out when oil prices exceed a certain level which is adjusted annually for inflation. A schedule showing historical inflation factor adjustments is included at the end of this paper. The 1997 credit would have begun to phase-out if oil prices had exceeded $47.78 per barrel, and would have been completely phased-out if the price per barrel had exceeded $59.98. The credit is reduced by the amount of grants or subsidized financing used to fund a particular project, and is

coordinated with certain other tax credits to prevent double usage of credits. The §29 credit will not offset alternative minimum tax, and will offset regular tax liability only to the extent that it exceeds alternative minimum tax. Any unused credit in a particular year may not be carried backward or forward to any other year, unless the credit is not used due to an alternative minimum tax limitation, in which case the disallowed portion will increase the minimum tax credit carryover.

The Internal Revenue Service does not publish specific tax forms to aid taxpayers in properly reporting the §29 credit. However, Gomel & Davis, an Atlanta law firm, has devised such forms. Copies of these forms are included as attachments at the end of this paper.

VIII. MONETIZATION OF CREDITS

Under §29, a taxpayer desiring to utilize the tax credit must have:

1. Produced a qualified fuel;
2. In a well drilled or facility placed in service within the requisite time frames; and
3. Sold such qualified fuel to an unrelated third party.

An owner of a qualified property who is not able to use the tax credit may sell an economic interest in the property to a tax oriented investor who is able to use the tax credit. The purchase price of the property may include a mark-up amount that reflects the value of the §29 credit. Such a transaction is referred to as a "monetization" of the credit. When structuring the monetization of §29 credits, it is of utmost importance that the production of the qualified fuel be attributable to the taxpayer. For a §29 tax credit from coalbed methane and tight formation gas, recent private letter rulings indicate that the tax investor need not expect a profit from current operations. However, in order to receive all of the available §29 credit, the tax investor must acquire a complete economic interest in the subject property and the seller is not allowed to retain a current economic interest in the subject property. An economic interest in mineral property is obtained by an investor who secures income which is derived from the extraction of the mineral and where such income is the basis of a return of his capital. The term includes working or operating interests, royalties, overriding royalties, net profits interests and production payments, unless treated as loans under another section of the Internal Revenue Code. Therefore, although the tax investor may not have to demonstrate a current "for profit" motive to pass tax scrutiny, the investor will have to acquire economic benefits and burdens relating to the property to be considered the true gas producer who is entitled to the §29 credit. One such economic benefit and burden is the requirement that the investor have a potential to receive additional economic benefit from the remaining reserves after the credit expires. The transaction should not deplete the property of all economic benefit during the life of the tax credit and production payment period.

Typically, transactions for monetization of §29 tax credits are structured substantially as follows to pass Internal Revenue Service scrutiny:

1. The tax investor is the buyer of the working interest and acquires the interest in exchange for a small cash down payment and an installment obligation that is equal to as much as 100% of operating profits from the property plus a fixed percentage of the §29 credit. This installment obligation must be recourse, meaning that the obligation to pay must be backed by additional assets or guarantees that extend beyond the

property being purchased. However, the recourse may be limited to the §29 payment amount.

2. The payments stop after a specified period, when production is expected to have used up a designated amount of the reserves estimated to be in the ground at the time of contracting (which may be 75% to 80% of these reserves). Also, when the interest is purchased, the estimated present value of the production after the payments end is greater than 5% of the present value of the entire production from the subject property. These estimates are typically provided by an independent engineering firm.
3. The seller can retain the right to additional reserves discovered in the future, but the seller usually retains only a percentage of these future additional reserves.
4. The original owner of the property may continue to manage the property under a management agreement with the investor.
5. As new owner of the property, the investor is responsible for payment of all costs and expenses associated with the property. Since the installment payments equal up to 100% of the proceeds from the property, the investor may potentially incur costs and expenses that have to be funded from sources other than production from the property. In order to assure that there are sufficient funds to pay the costs to operate the property, the investor is usually contractually required to make further contributions to pay operating costs that are in excess of proceeds from the property. These contributions may be limited to the §29 payment amount. In certain instances where the seller continues to act as the operator of the facility, the investor may be able to obtain an operator's indemnity for any losses resulting from the operator's management of the property. In such instances, the investor could be indemnified for further contributions to pay operating costs.
6. The original owner may have the option to buy back a portion of the remainder of the property for fair market value.

Under these general circumstances, the Internal Revenue Service has ruled that the investor in the property qualifies for the §29 credit. This qualification is permitted because the original owner sells its economic interest in the property to the investor, retaining only an installment obligation from the investor that constitutes a non-continuing interest in the production and a possible percentage of future discovered reserves. The percentage of payments the seller receives in respect of the §29 credit is not considered an economic interest because the amount payable to the seller can exceed the gross income from the property. Additionally, pursuant to Internal Revenue Code §636(a), the installment obligation to the original owner is considered to be a purchase money mortgage loan rather than an economic interest even where it is payable solely from production so long as it has a payment period that is shorter than the productive life of the transferred property. The percentage of future discovered reserves is only a "possibility of reverter" and is not considered a present economic interest.

IX. EXAMPLE OF A HYPOTHETICAL MONETIZATION TRANSACTION

The following example illustrates the economic benefits to both the seller and the investor in a hypothetical §29 monetization transaction. Assume a transaction involving a coalbed methane project has the following projected economics:

1. The investor purchases the property for:

A. $100,000 cash down payment.
B. Payments equal to 100% of proceeds from the production of the gas for the period beginning January 1, 1999 and ending December 31, 2002.[2]
C. Payments equal to 75% of the §29 credit generated from January 1, 1999 through December 31, 2002.

2. The estimated reserves from January 1, 1999 through December 31, 2002 have a present value of $3.0 million.
3. The §29 credit on production during this period has a present value of $2.0 million.
4. The estimated reserves after 2002 have a present value of $200,000 (which is greater than 5% of the present value of all production: $3.2 million x 5% = $160,000).

After completion of the transaction, the investor and seller can expect the following benefits (payments are shown in brackets):

	Seller	Investor
Value of Total Reserves Sold	$(3,200,000)	$3,200,000
Down Payment	100,000	(100,000)
Value of Production Payments 1999 - 2002	3,000,000	(3,000,000)
§29 Tax Credit	-0-	2,000,000
Payments for §29 Tax Credit	1,500,000	(1,500,000)
Net Benefit	$1,600,000	$ 600,000

In summary, the seller in the above hypothetical receives a cash down payment up-front, all the income as a result of production and a payment equal to a percentage of the §29 credit. The investor receives the §29 credit which he can utilize against his tax liability. Additionally, after the credit expires, the investor has the potential to receive additional economic benefit from the remaining reserves. Obviously, this hypothetical is over simplified, but it is intended to outline the basic economic effects of a monetization transaction.

X. CONCLUSION

Section 29 may apply to coal seam gas sold to unrelated buyers by December 31, 2002 provided the taxpayer meets the following criteria:

1. Obtain “final determination” from federal or state governmental agency with regulatory authority over natural gas indicating that the gas from both the field and the individual well is derived from a coal seam.

[2] Expenses are disregarded for simplicity.

2. File notice with FERC regarding “final determination” of coal seam field and individual wells.
3. Establish proof of well drilling date(s) - applicable window for §29 is 1/1/80 to 12/31/92.
4. Confirm that coalbed methane was not marketed from the property before 1/1/80.
5. Confirm that the well(s) penetrated the coal seam between 1/1/80 to 12/31/92 (no additional vertical drilling is allowed, although horizontal recompletions may be permissible).
6. Ensure that all gas will be extracted from the existing qualified wellbore(s).
7. If the wellbore is not a typical oil & gas well (e.g., a gob well, utility well, or ventilation shaft), then additional assurance from counsel (and perhaps Internal Revenue Service confirmation) may be needed to assure that it qualifies as a “well” for §29 purposes.

There are several possible types of wellbores at coal mines which may potentially qualify, but taxpayers should generally seek advice of tax counsel, and possibly obtain a formal opinion from the Internal Revenue Service, before relying on §29 qualification for new coal seam projects. This paper is intended to be used as a general guide to issues that may affect §29 qualifications for coalbed methane projects, but it is given as legal advice and may not be applicable to all situations. Taxpayers should seek advice from counsel before proceeding with §29 transactions or claiming the §29 to ascertain how the §29 requirements relate specifically to their circumstances.

Attachments

- Historical Inflation Factors for §29 (1 page)

- Tax Reporting Forms for §29 as prepared by Gomel & Davis, Attorneys at Law, Atlanta, Georgia (2 pages)

SCHEDULE D
SECTION 29 CREDIT
HISTORICAL VALUES & INFLATION ADJUSTMENTS
1980 - 1997

Original Credit = 3.00 Per Barrel Oil Equivalent
Original Phase = 23.50 to 29.50 Per Barrel Oil

YEAR	INFLATION FACTOR	CREDIT PER BOE	BARREL REFERENCE PRICE	PHASE OUT RANGE	CREDIT PER BOE ALLOWED
1980	1.0896	3.27	33.03	25.61 to 32.14	0
1981	1.1900	3.57	32.19	27.97 to 35.11	41%
1982	1.2676	3.80	28.50	29.79 to 37.39	100%
1983	1.3197	3.96	26.19	31.01 to 38.93	100%
1984	1.3673	4.10	25.88	32.13 to 40.34	100%
1985	1.4211	4.26	24.08	33.40 to 41.92	100%
1986	1.4555	4.37	12.66	34.20 to 42.94	100%
1987	1.4949	4.48	15.41	35.13 to 44.10	100%
1988	1.5483	4.64	12.57	36.39 to 45.67	100%
1989	1.6069	4.82	15.85	37.76 to 47.40	100%
1990	1.6730	5.02	20.03	39.32 to 49.35	100%
1991	1.7835	5.35	16.50	41.91 to 52.61	100%
1992	1.8430	5.53	15.98	43.31 to 54.37	100%
1993	1.8918	5.68	14.24	44.46 to 55.81	100%
1994	1.9207	5.76	13.19	45.14 to 56.66	100%
1995	1.9439	5.83	14.62	45.68 to 57.35	100%
1996	1.9837	5.95	18.46	46.62 to 58.52	100%
1997	2.0331	6.1	17.24	47.78 to 59.98	100%

IRC SECTION 29
CREDIT FOR PRODUCING FUEL FROM A NONCONVENTIONAL SOURCE
1997 COMPUTATION OF CREDIT AMOUNT

Names as shown on return:	Identifying numbers:

(1) Credit amount allocated to taxpayer
(from Form K-1 for partners or S Corp. shareholders) _____

(2) Reduction for certain credits:

(a) Energy Credit - IRC §48(a) _____

(b) Enhanced Oil Credit - IRC §43 _____

(c) Household & Dependent Care Credit - IRC §21 _____

(d) Credit for Elderly & Disabled - IRC §22 _____

(e) Credit for Interest on Certain Home Mortgages - IRC §25 _____

(f) Foreign Tax Credit - IRC §27 _____

(g) Clinical Test Credit - IRC §28 _____

(h) Total reduction for certain credits
---Total of Lines 2(a) through 2(g) _____

(3) Credit before AMT limitation
---Line 1 minus Line 2(h) _____

(4) AMT Limitation:

(a) Regular Tax:
For individuals, Form 1040, Line 39
For corporations, Form 1120, Schedule J, Line 3 _____

(b) Tentative Minimum Tax:
For individuals. Form 6251, Line 26
For corporations, Form 4626, Line 13 _____

(c) Subtract Line 4(b) from Line 4(a)
(If negative number, enter zero) _____

(5) Credit Allowed - Lesser of Line (3) or Line 4(c) _____

ENTER THE CREDIT ALLOWED FROM LINE (5) ABOVE AS FOLLOWS:

- **FORM 1040: INCLUDE IN LINE 45 ON PAGE 2. WRITE THE AMOUNT AND "FNS" IN THE DOTTED LINE NEXT TO LINE 45 AND ATTACH A SCHEDULE SHOWING HOW YOU FIGURED THE CREDIT.**

- **FORM 1120: ENTER ON SCHEDULE J, LINE 4c.**

- **ANY AMOUNT DISALLOWED FROM LINE 4 ABOVE DUE TO THE AMT LIMITATION INCREASES THE MINIMUM TAX CREDIT CARRYFORWARD TO 1998 REPORTED ON 1998 FROM 8801, LINE 20, FOR INDIVIDUALS; AND ON FORM 8827, LINE 3, FOR CORPORATIONS.**

CLIENT NAME

ESTIMATED FUEL CREDIT COMPUTATION
IRC SECTION 29

1997 TOTAL BTU's PRODUCED	-
DIVIDED BY BTU'S FROM GAS	0%
QUALIFIYING BTU'S	-
DIVIDED BY BARREL OF OIL EQUIVALENT	5,800,000
EQUIVALENT BARRELS	-
MULTIPLIED BY CREDIT RATE PER BARREL ($3.00 X 2.0214)	6.0642
ESTIMATED 1997 CREDIT	-